28 September 2021

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

by email: distribution.feedback@ea.govt.nz

Response to consultation paper- Updating the regulatory settings for Distribution Networks

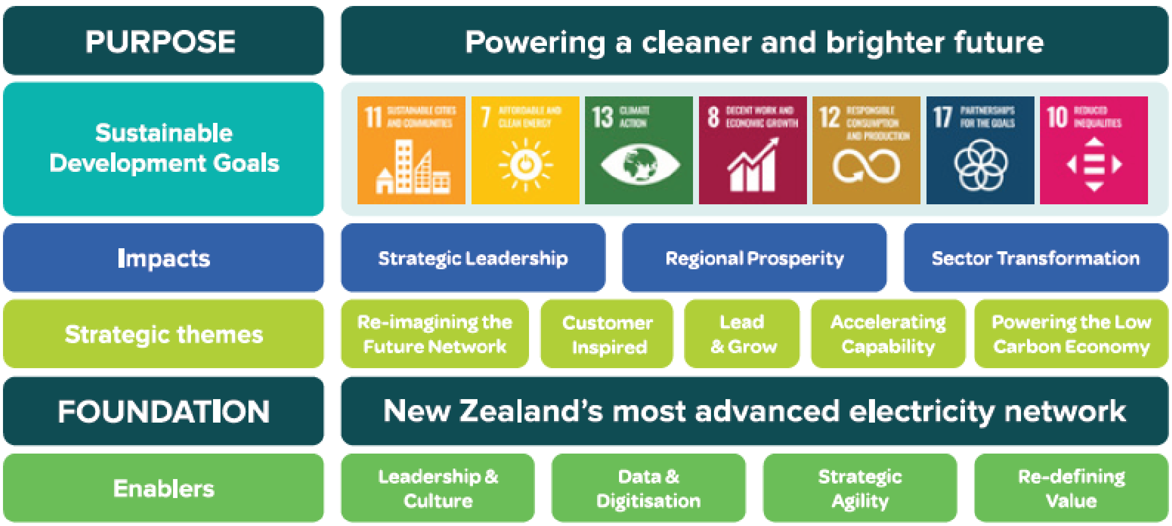
1. Orion New Zealand Limited (Orion) welcomes the opportunity to provide a submission on the consultation on updating the regulatory settings for distribution networks to the Electricity Authority (the Authority). In our submission we provide;

    - Orion specific context and high-level submission points and
    - our response to your specific questions.

2. Orion supports the ENA submission to the Authority.

Orion's orientation

3. As New Zealand transitions to a low-carbon economy, the energy sector has a critical part to play. Orion Group has established its Purpose, and developed its strategy, as shown below, to ensure it is a vital player in that transition for our community, our region and New Zealand. We believe our Purpose and strategy, along with our network roadmap setting out the critical initiatives we need to pursue, aligns with the themes of the Authority's paper.



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Scope of paper could have been broader

4. While we appreciate that no one paper can cover all relevant issues, we would like to highlight to the EA three areas that were not included in the consultation paper where we believe increased attention is required. All three stem from our belief that if New Zealand is to transition to a low-carbon future, then we need to place less emphasis on a "leave it to the market" approach and instead the industry needs to work together for better system outcomes.

5. The three areas we wish to highlight are:

   a) It is well recognised that most future generation installed in New Zealand over coming decades will be from renewable resources like wind and solar – with the vast majority of such generation being installed at utility scale locations. For investors to have confidence to invest in such generation plant it has been recognised by the EA, via MDAGs price discovery project, that one upcoming issue is the potential that significant amounts of renewable generation, which has very low short-run marginal costs to operate, may significantly reduce electricity spot prices – particularly at non-peaking times. This is likely to create a cycle where extremely low spot prices, caused by new renewable generation, then deters further new investment in generation even if consumer demand for electricity is ever increasing.

   b) In effect the EA/MDAG is considering how potential investors in generation can get greater confidence in the revenue they will earn from any utility scale renewable plant. We believe this examination shouldn't just be confined to spot price examination but include the potential for longer term offtake contracts or Power Purchase Agreements (PPAs) or similar agreements, to be established/encouraged. PPA's are being struck between buyers and sellers e.g.CEN selling offtake of Tauhara to GNE, Tilt (now MCY) selling PPA for Omamari to GNE (GNE has tendered for generation to replace its declining thermal). Independent Power Purchasers have struggled to get access to (in their opinion) competitively priced PPA's. By having contracts that extend beyond five to ten years, to more closely match the life of the generation assets installed, investors would have greater confidence in a projects viability and this would result in access to lower costs of capital (be it equity or debt). With lower cost of capital, we could expect to see average wholesale prices decline and cheaper electricity to result. The benefits of decarbonising our economy would be greater if investment certainty is increased.

   c) While we appreciate that New Zealand's high proportion of hydro and geothermal offers significant advantages to enable integration of more intermittent generation before hitting system stability problems, such as those experienced in Australia, we believe it important that we learn from such countries and prepare for this potential. Consequently, in our recent presentation to MDAG on the spot pricing issue, we highlighted this issue and asked the EA to consider:

      i) the merits of a NZ equivalent of the Australian Finkel report which looks independently at where improvements to our system security could be made

      ii) advance consideration of national requirements on the installation of batteries alongside utility scale intermittent generation. Presently there is no national guidance/requirements on when large fast discharge batteries, procured directly or via a third-party participant, are required to be installed alongside utility scale intermittent generation or to what extent existing hydro could offer services to support this higher penetration of renewables. Currently it is left to networks and Transpower to determine if batteries or support are required, and this naturally leads to early installers of intermittent generation potentially gaining first mover advantage. Australia has moved to national requirements on this matter.

iii) consider National guidance on how distribution networks are expected to pass on any Transpower injection pricing when export into a GXP occurs. Whilst we appreciate that such injection pricing may eventually be removed, if it is not then consistent treatment of how these charges are applied by distribution companies across the country would be useful and promote fair competition in the generation market.

6. The industry and the EA appreciate that:

    i. EV's are New Zealand's most important avenue for decarbonisation

    ii. EV's have the potential to significantly increase peak demand which would result in an increase in spend across the industry – generation, transmission and distribution network spend would all increase

    iii. Considered distribution pricing signals that encourage the charging of EVs at off peak times, and at staggered start times (i.e. all EVs don't start charging at say 9pm) have strong potential to minimise the necessity for infrastructure spend.

However, an ongoing and as yet relatively unaddressed issue is that whilst distribution pricing has the strong potential to minimise the necessity for infrastructure spend, this potential will only ever be realised if customers actually see these pricing signals. In other words, distributors pricing signals need to be passed on by retailers. To date this has not always occurred and certainly it has not occurred for most customers.

Consequently, we believe that the historic focus the EA and government has had on promoting competition and innovation in the retail market, needs to be balanced against the imperative the country now faces to decarbonise. The scales should tilt more in favour of ensuring decarbonisation occurs at the lowest possible cost.

This would suggest that there is a potential market failure in that TOU pricing signals cannot be guaranteed to flow through the retailer to the consumer, and that risks system security if EV charging is not controlled. This would suggest an increasing focus on demand flexibility and ensuring cost reflective pricing signals are passed onto most customers.

High level comments on the Authority's discussion paper

7. The Paper successfully lays out many of the challenges facing the sector and Orion agrees with the Authority on the general direction the industry must move to achieve our broader climate change objectives and meet our community's needs. We also agree with the Authority that distributors are a critical part of the solution and are in fact a key enabler for the future the Authority (and we) envisions.

8. However, we question the concern that the distribution sector is not oriented toward change and will be too slow to deliver. We submit that distributors don't need to move in "lock-step" in this transition. Factors such as constraint status of networks, customer uptake of emerging technology, geographical location and community needs will drive the tempo. We would also like to see more dialogue and alignment on the speed required to move on such challenges, when there is still fundamental

uncertainty on many of the issues, and consumer uptake of some emerging technology is low. We agree progression is necessary in a prudent way with appropriate focus on what is most pressing.

9. Orion submits it is important to avoid prescribing solutions or outcomes too soon given some of the fundamental uncertainties that remain on the likely speed of uptake of technology by consumers and the exact nature of the technology that will be implemented.

10. The Authority should be cautious about an early move to regulation that could ultimately hinder the future that the Authority and New Zealand desires. This is more likely to result in higher costs for our customers and potentially hinder New Zealand's efforts to decarbonise.

11. We submit that the next period is important for trialling technology, systems and processes, and sharing learnings across the sector and that funding should be made available to support these initiatives. An example on technology uncertainty is the question of whether, for management of EVs, price movements over the next few years lead aggregators/households to generally opt for smart EV chargers (V1G) or vehicle to home (V2H) or vehicle to grid (V2G) chargers? This decision on technology will cause a fundamental difference for network management and price offerings to the market.

12. Given this, we submit it would be useful for the Authority to better understand the planning, continuous improvement and innovations distributors are contemplating. We invite the Authority to visit us to gain insight into our roadmap and the actions we (and other lines companies) are taking to accommodate and accelerate the future energy environment.

13. The Authority indicated that pricing is outside the scope of this discussion paper and is the subject of other workstreams[1] . We recognise that pricing is a key enabler and is the least cost way to signal appropriate use of the distribution system. For example:

    iv. pricing can signal efficient times to charge DER such as electric vehicles
    v. pricing can facilitate better utilisation of existing network infrastructure
    vi. pricing can assist in minimising the investment needed for additional network infrastructure
    vii. pricing signals at distribution level are only effective if passed through to the customer through retail pricing. Retailers, from an energy system perspective, also have a responsibility to ensure efficient use of the infrastructure that provides the distribution service
    viii. pricing is likely to be the most cost-effective way to manage customer behaviour balancing that with customers' preference for simple pricing structures

    We are actively working on a new pricing strategy and roadmap that will be incorporated into our upcoming pricing methodology.

[1]The Authority plans to issue a draft of proposed enhanced guidance on efficient distribution pricing in spring 2021

14. The Authority indicates their intention to publish a draft of proposed enhanced guidance on efficient distribution pricing in Spring 2021. We are not aware of any engagement with distribution companies on this and we think this is an important part of the process before the Authority publishes its guidance.

15. The Authority appears to suggest that moving to a contestable market for DER is a priority. We would suggest, broadly speaking, a staged approach to this would be more appropriate, as DER scale grows over time. This provides us time to get this right. We note that the cost-benefit analysis set out with the paper, has concluded that around 85% of the value in the value stack for DER is fundamentally from the benefits of reducing peaks to offset the need to build new distribution, transmission and generation.

16. Stage 1 of any attempt to unlock the value of DER, and the stage we believe should receive the most initial focus, is targeting capture of 85% of the 'DER value prize' – namely peak load reduction. Much of this can be achieved through network pricing, which encourages use of DER to reduce peaks (through shifting load/charging to off-peak times and discharge to peak times), supported by customer engagement/education.

17. Stage 2, which will overlap with stage 1, should be focussed on the other 15%. Being only a small portion (15%) of the value of DER to New Zealand, it's important not to overly focus on this aspect, however an early win for the sector here would involve building agreement and clarity on the prioritisation of the value stack. All participants in the market seem to recognise that there may be times when system security must take precedence over opportunities to make, or save, money via DER. Theoretically such system security events could potentially be 'priced' into the market and take precedence over other activities simply by having the highest price, however a coordinated discussion about this within the industry needs to occur. We suspect that building agreement and clarity on the prioritisation of the value stack, and where system security fits into it, and mechanisms to deal with it, would alleviate much of the concern that leads the Authority to suggest that distributors may favour in-house solutions.

18. Also, an important consideration for the Authority and the Commission is how existing peak load management (demand side management) can be retained and physically maintained[2] because long-term secure access to manageable load is paramount. For instance, both hot water control and potentially space heating control should not be underutilised as they both exist now and could expand[3] given their relative lower cost to DER alternatives like solar PV. Otherwise infrastructure investment to address HILP[4] peak events will occur that can't be undone.

19. Further to the above points, for several years the Upper South Island load management group has worked together to get the best value for our customers out of demand side management. This group was formed to work together to manage load in the Upper South Island and manage demand during times of upper South Island grid peaks. While there will be changes to the TPM, including removal of the RCPD charging component, the group's intentions are to continue to work collaboratively to

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[2] For instance, ripple control of hot water

[3] For instance, through initiatives by EECA to displace old less efficient home appliances with modern controllable efficient alternatives which also has the potential to benefit vulnerable customers through lower ongoing consumption levels.

[4] High impact low probability

manage load on the upper South Island grid, with the primary objective of avoiding the need for grid investments.

20. We submit that it is premature for the Authority to apply prescription or mandate approaches and standardisation for operating agreements in the short term. This market is emergent and so time needs to be given for exploration and flexibility to try these solutions out and capture learnings. We are open to non-network alternatives and are seeking to improve our transparency about where constraints exist in service of identifying economic solutions that can provide the appropriate level of service compared to traditional solutions.

21. The paper indicates that the Authority sees an issue with EDBs owning utility scale batteries[5]. We submit that in the early stages of this transition, when the market may not be able to provide, there is not a significant issue from EDB ownership of utility scale batteries (>1MW) and that the Authority should be more open to EDBs owning and operating these on their own networks. Especially given 85% of the benefit is largely related to avoiding transmission and distribution investment (refer point 16 above). This will allow the sector to build understanding of this technology while benefiting their own customers and the sector by advancing the use of the technology. An investment in utility scale batteries connected to the network is unlikely to occur unless it is an economic and efficient investment compared to other alternatives. The Authority is also reminded that the Electricity (Industry) Act prevents distributors from having a generator of more than 50 MW without corporate separation and arm's-length rules[6]. This provides existing control on distributor activity in the DER space at the high end.

22. We summarise our high-level positioning on the level of intervention for the Authority's specific question groupings as;

    - Information on power flows and hosting capacity (data)- significant
    - Electricity supply standards- medium
    - Market settings for equal access- minor moving to medium
    - Operating agreements- minor
    - Capacity and capability- minor moving to medium

    We provide further commentary on this in Appendix A.

[5] The Authority states in point 2.8 on page 14 that "DER can be owned by consumers but can also be owned and/or operated by third parties or distributors." Yet in point 6.44 page 52 the Authority considers in a significant issue scenario that "Distributors could still own and operate DER on other networks except their own." The paper indicates in point 6.46 page 52 that "The Clean Energy Package in the European Union prohibits distributors from owning storage or EV charging infrastructure unless they can demonstrate to the regulator that the market cannot provide."

[6] Electricity (Industry) Act Part 3 Clause 72(20(b)(i)

23. Our response to your specific questions is informed by the orientation we describe above and is included in Appendix B.

Concluding remarks

Thank you for the opportunity to provide this submission. We do not consider that any part of this information is confidential. If you have any questions please contact Dayle Parris (Interim GM Commercial), DDI 03 363 9874, email dayle.parris@oriongroup.co.nz.

Yours sincerely

Dayle Parris
Interim GM Commercial

Appendix A- Our positioning on the level of intervention

Information on power flows and hosting capacity (data) (paper page 29)

We submit that information on power flows and hosting capacity is a "significant issue" with our preferred solution being shared data through API. The issue of data access more generally will be important to the future functioning of the energy market. On data CEER[7] in their paper to the European Commission Public Consultation on the Data Act stated that "Issues such as data portability, data access rights for third parties and government, data control and cybersecurity as well as privacy issues must be addressed within a harmonised framework." A data governance framework addressing data exchange, portability and interoperability for the energy sector should be a primary objective of the Electricity Authority. Ultimately, as the CEER paper states "Digitalisation can, among other things, bolster cost savings, convenience, consumer choice and participation as well as overall quality and security of supply of the system." We provide further commentary in response to specific questions 1 through 3 in Appendix A.

	Minor issue	Medium issue	Significant issue
Options	• Inform and educate consumers on how to request their consumption data • Encourage distributors to collaborate in finding the most efficient way of capturing and publishing utilisation data	• Assess options to implement shared data arrangements • Publish guidance for distributors to report on export congestion and network investment needs	• Shared data through API • Central meter data store

Electricity supply standards (paper page 41)

We submit that electricity supply standards are a "medium issue" with particular emphasis on laying foundations for standards and DER registry. The threat of regulation is a moot point because EDBs are already firmly regulated via the Commerce Commission, the Authority via the Code and through a number of other acts and regulations. We provide further commentary in response to specific questions 4 through 9 in Appendix A.

	Minor issue	Medium issue	Significant issue
Options	• Voluntary guidelines • Develop templates • Education and awareness	• Recommend standards templates • Threat of regulation • DER registry • Lay foundations for standards	• Mandatory uniform standards

[7] Council of European Energy Regulators- paper link CEER report

Market settings for equal access (paper page 48)

We submit that market settings for equal access is a "minor to medium issue" with targeted emphasis in the medium space on funding of trials. We provide further commentary in response to specific questions 10 through 13 in Appendix A.

	Minor issue	Medium issue	Significant issue
Options	• Education on flexibility services • Require distributors to disclose progress • Publish a comparative report	• Fund trials • Distributors required to prove that they have fully explored flexibility	• Link distributors' regulated revenue to their progress in developing the use of flexibility services

Operating agreements (paper page 56)

We submit that operating agreements are a "minor issue" at this early juncture in the developing flexibility services market. We provide further commentary in response to specific questions 14 through 17 in Appendix A.

	Minor issue	Medium issue	Significant issue
Options	• Develop guidance for operating agreements	• Establish a 'DDA style' agreement which parties can opt in to	• Establish a mandatory set of terms that parties must use

Capability and capacity (paper page 60)

We submit that capability and capacity are a "minor to medium issue" with particular emphasis on DNO/DSO role clarity and coordination in the medium space. We caution a move to price quality regulation for all EDBs and refer you back to our point 4 above. We provide further commentary in response to specific questions 18 through 20 in Appendix A.

	Minor issue	Medium issue	Significant issue
Options	• Encourage collaboration • Improve transparency of investment decisions • Develop a reporting framework for distributors and DER suppliers to report results of trials	• Impose price quality regulation on all distributors • Clarifying the roles of a distribution network operator (DNO) and a distribution system operator (DSO) • Create industry body to body would promote coordination of DSOs • Encourage joint-venture arrangements	• Adopt a single DSO model

Submission by Orion on updating regulatory settings for distribution networks

Appendix B

Information on power flows and hosting capacity

Q.1 Have you experienced issues relating to a lack of information or uneven access to information?
Yes. Distributor access to smart-meter data is inconsistent. As a general comment, we have found that access to smart metering information on an ongoing basis has been difficult as retailers have seemed reluctant to engage. Most recently we have begun the process to negotiate data agreements, in line with the DDA data template, with a subset of retailers. Barriers we are encountering in working that process through include; • retailers taking time to compare different data agreements across EDBs, • retailers reluctant to consider minor changes from standard for reasonable reasons, • retailers using the data agreement negotiation to re-open negotiation on the DDA; • some retailers indicating that they will have difficulties in providing regular monthly data updates. We have not yet secured any data agreements for ongoing supplies of data however we believe we are close with one retailer. Some smaller retailers do not have robust systems in place to supply data and the data we are able to obtain often arrives with missing information and formatting errors e.g. from manual processes. Access to data is critical. Understanding what is happening at each consumer premise is becoming more important. This information allows distributors to develop load profiles and better understand what is happening on the low voltage network, especially as levels of DER uptake increase and as seasons change. Intervention can then be targeted and timely thereby reducing investment and subsequent cost to customers. Access to data, as some distributors have, would provide improved customer service including power quality, outage response and resolution of hosting capacity studies. Companies with access to data can reduce costs (truck rolls)[8], improve fault response and better understand their network without adding significant additional costs for their customers. Distributors without access to this data have resorted to other methods to increase the visibility of the LV network, such as transformer monitoring. These systems require lead time and significant investment in equipment and data architecture which impacts costs for all customers on the network. Consequently, this approach is usually applied in a targeted way. However, one distributor has installed their own duplicate smart meters to gather this information. The impact of this is that customer costs have increased, so customers are paying more to provide that distributor access to information which already exists and is held by the retailer through their MEP arrangements. From a system perspective, this cannot be a prudent use of resources.

[8] Applies only where meters have a last gasp facility

Q.2 What information do you need to make more informed investment and operation decisions?

At Orion we do not have access to smart meter data, and as such began investment in low voltage monitoring systems to improve low voltage network visibility. These systems provide greater visibility of the current operating conditions/performance of the transformer and outgoing circuits along with hosting capacity, but without non-aggregated, non-anonymised smart meter data in future we may still experience unforeseen issues within the downstream low voltage circuits. This could appear in the form of reduced end-of line voltage issues under high EV charging load conditions in winter, or possibly by increased circuit voltages or intra-circuit power-quality issues under high-PV uptake conditions in summer (less likely).
 	
Access to historic smart meter data files (half-hourly usage files) would allow creation of typical customer load profiles, which could be used within the ADMS[9] system to improve the quality of power flow calculations on the low voltage network. It would support our initial model-based decisions with real world data. It also avoids the potential need to develop and invest in off-line hugely complex state-estimation modelling. This historic data can be combined to create an improved historic understanding of asset utilisation and improve long-term planning decisions around asset upgrades.
 	
In the event we have access to smart meter data, we would reassess the extent of our LV monitoring investment programme. Near real-time smart meter data combined with targeted transformer monitoring allows for a high-resolution view of the low voltage network, allowing distributors to understand the operating conditions of any part of the low voltage network at any time. We'd then be able to have an even more targeted LV reinforcement programme for beneficial DER support and better operational management of the system. Ultimately, this will also support transparency and coordination of DER and flexibility services that would benefit customers.
 	
The recent grid emergency event of 9 August highlights the growing need for this data. Because of the climatic conditions of that day our Network and the Grid were pushed to levels we have not experienced. The visibility of our LV network is crucial to ensure we can supply these increases and maintain the quality of supply by building in prudent levels of resilience in advance of these HILP[10] events. Data can also be used to understand what tailored solutions might be needed/supplemented or for alternative solutions to the traditional line function services e.g. to protect vulnerable customers in the transition.
 	
Types of data that would be useful include:
• Power quality information (e.g. voltage profiles, power factor, harmonics) that will enable us to rectify system abnormalities
    o to provide a leading indicator to where potential power quality issues may be developing on the network to allow pre-emptive action before this causes issues with or potential damage to customer equipment.
    o In a higher DER future (PV particularly) there is increased risk of harmonics or voltage issues and having this data allows us to act in a more anticipatory and timely way. In the correct format (instantaneous recording) voltage information to detect loss of neutral from phase displacement or high flicker levels would support network health and safety.
    o In the future if smart meters evolve to include advanced power quality functions the use case for this data will increase.
 	
• Last gasp (where available from meters)

[9] Advanced distribution management system
[10] High impact low probability

  - to improve customer response and outage reporting in event of a fault/loss of voltage. We could immediately see which customers have lost supply (although might have to contend with some false positives), and target response crews to the best location with reduced fault-finding time improving response for all sites.

- Mass market interval metering information to;
  - inform the restructuring and reform of our pricing.
  - apply prices, using cost reflective and service based chargeable metrics (for example, capacity based or peak demand charges).
  - plan for and undertake efficient and timely reinforcement of our low voltage network as our community decarbonises through electrification and development of local renewable energy resources.
  - provide more insight to what is happening at a customer connection compared to developing models based on assumptions of the load distribution down a feeder (voltage profile and load). This will allow more targeted reinforcement and would give more confidence to contingency situations (where load must be carried via an abnormal switching configuration).

- Location of EVs to;
  - identify EV clusters and improve our ability to proactively configure or construct the network to handle any changes to peak load. Without knowing where EVs are, we are reliant on monitoring to identify increased load – which may or may not be an EV. If we can identify EVs are clustering in a specific area where we have network constraints, then we can look to either reinforce the network, tender for flexibility options at peak times, or apply a pricing arrangement to encourage charging at a time when the network in that area can manage the load.
  - the knowledge could increase our flexibility options as EVs in future could be a load or a source of supply.

- Location of non-standard in home or on-route EV charger capacities e.g. >7kW to;
  - as above
  - provide the opportunity to explore controllable load opportunities or
  - use future V2G to provide non-network reinforcement in our own right or via requests to third parties.
  - We note most of these types of connection would need a capacity upgrade therefore installers still have regulated obligations to see the supply meets the requirements of the installed equipment.

We also think that better public awareness of requirements for applying to and notifying networks of distributed generation is necessary.

Options, pros and cons

Q.3 What options do you think should be considered to help improve access to information?

Data access is a significant issue and we strongly advocate for a shared data access through an API solution which would address the current issue with inefficient and inconsistent access to data for reasonable cost and service flexibility.

Distributors need data to support us to develop better understanding of our low voltage systems. As data access increases we can consider network impact including congestion and constraints from both a load and export perspective. The low voltage network needs to be fit for purpose from both these perspectives.

Currently distributors have information on network congestion/constraints, and retailers have access to smart meter data. The real power comes in combining this information to understand what issues exist on the network and the behaviour of each individual connection (in a high DER environment going forward), so we are in a good position to influence consumer behaviour and provision of flexibility services in near real-time to solve congestion issues. We consider this to be a medium issue and therefore standardising the methodology distributors use to publish and report on network congestion issues allows for optimised decision making on behalf of DER providers, and consistency of approach nationwide, minimising confusion and maximising the connection of the right DER in the right place.

In the interim, the EA should support direct access to MEP data through the data agreement template agreed by ERANZ and ENA. The use of a data agreement however still represents an inefficient means for EDBs to gain access to information that in the short term will mean better planning decisions and information for third parties and in the long terms will be fundamental to dynamic operation of the network.

The Authority should work with industry to agree and provide standards, policy and governance for data exchange. This prescription is required before considering an API approach. An API is on demand and would be more aligned with the dynamic system of the future. Data security using credentials would be a feature. We consider a central data store an inferior solution- data ages, standards are still needed, expensive for capability, greater bandwidth needed when sending data.

Ultimately, an API solution will provide flexibility and be fit for purpose based on different sizes and scales of participants. It costs participants to gather and obtain data so there must be value in this data.
In addition, the EA should support out-of-market trials, with distributors and retailers/MEPs, for sharing of bulk real-time data with learnings shared with the industry. This would prepare the system better for when new participants emerge in the market e.g. flexibility service providers (FSP) or DSO[11].

[11] Distribution system operator

Electricity supply standards (ESRs)

Q.4 Have networks experienced issues from the connection or operation of DER?
No material issues to date. Orion has a well-established connection process[12] and reaches out to installers/electricians building relationships with them so that expectations are understood between us and customers get good outcomes. We currently have 4,183 DG connections totalling 85,205 kW on our network, being a combination of liquid fuel, water, wind, solar, and solar/battery. Of this approximately 3.8% would be available for flexibility services from solar/battery combination and 75% from diesel standby/emergency generation. To date during 2021 (up to 11 August), across all applicants we have approved 88% of applications within three days. We have not declined any applications for connection of DG to our network. To date we have not experienced material issues from connection or operation of DER. In the last six years we have had occasion to investigate operational issues related to DG in approximately 4 situations. These issues, like load-based power quality investigations, were able to be resolved through a combination of circuit rebalance and inverter settings. Ongoing improvements in inverter technology will assist in minimising issues and providing flexibility to resolve issues as they arise. We envisage that issues may become more prominent as we experience increasing uptake, and clusters, of EVs on the same feeder or distribution transformer. We view EV charging as a more pressing issue than solar DG connection. Therefore, access to data, and in particular half hour metering data, is so important. In the interim we have undertaken detailed studies of our capacity to accommodate additional DG and EVs on our low voltage network. We have identified a subset of circuits that will require reinforcement over the next few years due to a combination of increasing EV load and an accumulation of in-fill housing. In the short term these LV circuits will likely require traditional network reinforcement as controllable DER solutions are unlikely to be available at mass to solve the issues. This is due to a combination of factors including: - Any initial LV circuit issues identified are likely to increase as more EVs are added. The speed that EVs are introduced to any particular LV circuit is currently unknown but it could be rapid. Timing is important. - Thus, any alternative DER solution that is implemented will need to be of sufficient size to not only correct the existing and immediate LV constraint but also allow ‘capacity headroom ‘for the short-medium term. If the DER solution is unable to deliver this then a traditional solution rolled out immediately will lower ultimate costs to customers. - Non-traditional DER solutions like V1G, batteries or V2H/V2G remain expensive and at cost levels well beyond what most customers regard as reasonable. Based on forecasts, from the likes of BloombergNEF, NERL, IRENA, Lazard, Element Energy, uptake in the next five years is likely to remain relatively low for this technology and certainly not at levels that will likely address imminent LV circuit issues.

[12] https://www.oriongroup.co.nz/customers/how-to-connect-to-our-network/

In the medium term, the five-ten year horizon, we believe these non-traditional DER solutions will begin to appear in sufficient quantities, with the necessary technical features, and at low enough cost levels, that they will become viable alternatives to traditional LV reinforcement.

If V2H or V2G becomes viable – and we increasingly suspect that it will and will almost leap frog V1G and stand-alone batteries as the option for households – the need for LV reinforcement will be somewhat mitigated, and potentially our LV peaks could decline (rather than simply having a lower growth rate). In fact, the potential for V2H or V2G to be 'game changing' is one of the very reasons we urge caution on the EA rushing into intervention now as the issues that need addressing in five-ten years' time may be very different to what they currently are.

Q.5 Do the Electrical (Safety) Regulations require review? If so, what changes do you think are needed (a) in the near term and (b) in the longer term?

Yes

In the near term

- As the Authority notes the original AS/NZS 4777.1:2005 standard is still referenced in the ESRs as the primary standard covering inverter installation safety. The Authority has previously referred the issue to MBIE and understands MBIE intends to update the reference to the latest standard in due course. It is important that updates to standards are correctly referenced in the regulations however a more agile approach would be to reference the standard along with stating "or the most current update". This means users are not inhibited from using the most up to date version of a standard instead of waiting for the time and cost involved in the administrative process of updating the regulations to allow it. It is better for customers if we can evolve with improvements in technology and standards, so they can gain the benefits.

- We note that the performance aspects of this standard (what the inverters can do) are in AS/NZS 4777.2 which won't be in the ESR's. Referencing this standard in EDBs network codes encourages compliance with AS/NZS 4777.2 and provides the flexibility to readily update the Network Code as the standard evolves with the technology available.

- We recommend that the electrical safety regulations refer to the harmonic standards, AS/NZS 61000.3.6, or the most current update. This will be more important with increasing levels of DER and clustering of DER.

In the longer term

- We submit that it is timely to initiate a review of, with reference to the electricity safety regulations, the regulated voltage and what constitutes an acceptable range for New Zealand in an environment of decarbonisation and increased DER connection. The scope of this review would need to consider whether a shift would
    - a) provide useful flexibility for DG connection and reduce the necessary level of investment in the low voltage system over time but especially in the short to medium term
    - b) have any material detrimental impacts on the operational life of household appliances in the medium to long term

- Clause 28 of the electricity safety regulations 2010 specifies what standard low voltage is (230V) and the range in which this must be kept (±6%). Australia is leading the way in terms of DER connection and we note that they have reviewed the rules for regulated voltage by shifting the standard low voltage setpoint and the acceptable ± range. A beneficial outcome from this, especially broadening the range on the low end given the undervoltage impacts of DER can result in the need for low voltage network reinforcement, is to reduce the level of network investment needed to maintain the regulated voltage and allow space for additional DER connections.

28 Voltage supply to installations

(1) The supply of electricity to installations operating at a voltage of 200 volts AC or more but not exceeding 250 volts AC (calculated or measured at the point of supply)—

(a) must be at standard low voltage; and

(b) except for momentary fluctuations, must be kept within 6% of that voltage.

(2) The supply of electricity to installations operating at other than standard low voltage (calculated or measured at the point of supply)—

(a) must be at a voltage agreed between the electricity retailer and the customer; and

(b) unless otherwise agreed between the electricity retailer and the customer, and except for momentary fluctuations, must be maintained within 6% of the agreed supply voltage.

(3) A person who supplies electricity commits an offence and is liable on conviction to a level 2 penalty if he or she supplies electricity to an installation in breach of this regulation.

Q.6 Does Part 6 remain fit for purpose? If not, what changes do you think are needed (a) in the near term and (b) in the longer term?

No

In the near term

We would support an additional process threshold for DER greater than 1MW. For connection of DER of this size the assessment process will be bespoke, and we believe it would be fair and reasonable for EDBs to have scope to charge actual costs for this level of investigation. Presently we are limited to that specified in Schedule 6.5 of Part 6. In addition, the timeframes are unrealistic for this level of investigation.

Electricity Registry: We support a mandated DER registry. We submit that it is timely to review the way in which DER can be recorded in the Registry. Are we recording inverters connected or DER connected? If we are recording inverters connected this can be a one to many relationship (e.g. inverter to solar and battery) or a many to one relationship (e.g. inverter to solar, inverter to battery and inverter to electric vehicle). Is it important to know how many kW are connected of each type or is it still appropriate to aggregate the total? The controllable device is the battery, but these are currently loaded as 'other' so become less traceable.

In the long term The uptake of EVs has the potential to cause capacity, voltage and other issues on a distribution network – particularly at the LV level. As the Authority is aware, EDBs, Orion included, often do not have great visibility of their LV networks. Consequently, the knowledge of where DER is connecting and connected to distribution networks is vitally important to EDBs. Whilst regulations allow EDBs to know where solar and batteries are installed on our network, we have no immediate knowledge of where EVs are located on our LV network. Currently NZTA only releases information on the suburb that EVs are registered in. More detailed information on the location of the registration is needed. To get this more detailed information, requiring electricians to comply with Part 6 for controllable EV chargers would be challenging – as proven by the fact that at present it is possible that a customer can connect an inverter for solar or solar/battery without our knowledge subject to metering requirements. Consequently, we would like the Authority to consider whether there is some work the Authority could lead in conjunction with NZ Transport Agency to allow access to EV registration data for network planning purposes? For instance, could the Authority work with the NZTA to provide anonymised street level registration information to EDBs or provision of aggregated "mesh block" MEP data via API so cluster analysis on peak loads can be undertaken to identify EV hotspots? . Such information would maintain the privacy of the household concerned but provide very valuable information for EDB network planning and decision making.
Q.7 Is there a case to be made for minimum mandatory equipment standards for DER equipment, specifically inverter connected DER?
There are two considerations in response to this question, (a) safety and (b) controllability On safety we think it's important to ensure minimum mandatory equipment standards for protection so customers are safely connecting and charging their DER. The installation requirement of a type B RCD or a type A with RDC-DD (Residual direct current detecting device - see **3.1.5**) to protect mode-3 charging equipment is in our opinion justified. On controllability of chargers we believe it is too early for minimum mandatory equipment standards for EV charging. SNZ PAS 6011:2021 is a well written easy to understand document that explains the hurdles that EDBs face with increasing load from the uptake of electric vehicles. Section **1.4.2 and 2.2** explains in simple terms that EDBs will eventually require some control through response signalling of EV charging. In our opinion, the use of pricing signals is a better approach to EV management in the near term while EV uptake is low and we want to encourage electrification of the transport fleet for decarbonisation. Loading additional mandatory equipment costs in the EV purchase and charging decision may be an unnecessary disincentive for customers at this time. This question should though be addressed in say five years when networks have had time to witness the success of new forms of pricing and we know more about the likelihood of V2G implementation.
Options, pros and cons
Q.8 What standards should be considered to help address reliability and connectivity issues?

Of the Authority's options assessment on page 41 of the paper we would support an assessment that this is a medium issue for the sector. Attention to a DER registry is a matter the Authority should be considering on its own data and digitisation roadmap. We support any education and guidance that helps the sector to understand requirements on them and the part they need to play in the supply chain. We appreciate that mandating EV PAS guidelines does add some cost for customers but consider this is not material compared to the initial EV purchase itself and the safety benefits at the electrical installation from applying the guidelines. Electric vehicles are potentially New Zealand's biggest impact for decarbonisation and there is benefit in mandating EV PAS guidelines, in relation to safety rather than controllability, early rather than later. This way customers can factor in the full cost of the EV decision rather than additional costs being imposed some time down the track after the initial purchase. Raising the awareness of power quality standards (e.g. the AS/NZS 61000 series) is important moving forward. We think, at this early stage, it's important to work with customers and resolve any issues as the need arises.
Q.9 Is there a case to look at connection and operation standards under Part 6 with a view to mandating aspects of these standards?
We submit that it is too early to take the prescriptive approach of mandating connection and operation standards and/or mandating aspects of them in Part 6. This approach may reduce the flexibility needed for updating approaches as experience increases and the market evolves. Our local electricians are familiar with the way we currently operate, and the risk of National alignment is that the process could become over-complicated and the cost to change could outweigh the benefits.

Market settings for equal access

Q.10 What flexibility services are you pursuing?

In our network we have a high voltage architecture that is substantially meshed with alternative supply routes (N-1). This means that for large parts of the network non-network alternatives may not be required for some time but in saying that there will still be niche opportunities where they could be of benefit. We will be more likely to want them in the nearer term at the low voltage level as DER connection increases. As an example, we are discussing potential flexibility services related to EV management in conjunction with the connections we have made as part of the Energy Accelerator[13] initiative.

As noted above data access is a fundamental enabler for flexibility services and network planning. We submit that the Authority should consider incentivising retailers/MEPs to provide meter data to participants at an appropriate price. Data is key to unlocking DER value.

Q.11 Are flexibility services being pursued through a competitive process?

We are not pursuing any specific flexibility services for traditional engineer solutions currently. If we were it is likely we would issue a request for proposal (RFP) to the market.

However, we will be looking to undertake trials of potential flexibility options in the future. The cost of these trials is still expensive – but significantly less than it was only a couple of years back – and as such trials have reached the stage where they are more justifiable in terms of benefits versus cost for our customers. Also, improvements in technology have occurred in the last couple of years, again meaning the timing for trials is more appropriate now than it was only a couple of years ago.

In relation to trials, we note the lack of government funding for such trials. Instead, each network's customers effectively fund trials, when trial findings would benefit the whole country. Thus, only a small subset of customers pays for potentially nationally beneficial findings. This doesn't seem equitable and we encourage the EA to consider what it can do to develop a national trial funding arrangement or for the funding available via the existing Commerce Commission's innovation allowance[14] to be expanded.

Options, pros and cons

Q.12 What options should be considered to incentivise non-network solutions?

Of the Authority's options assessment on page 48 of the paper we would support an assessment that this is primarily a minor issue at this time but would also support funding of trials where learnings can be shared.

We submit that the Authority could incentivise non-network solutions by gathering a central register of non-network/third party providers and making this available to participants to assist awareness of providers and requests for proposals. The EA could also host information sharing events that help participants to understand flexibility traders offerings and business models or provide fact sheets and other easily accessible information along the same lines.

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13 [13] https://www.orionaccelerator.nz/meet-the-startups

[14] We have also suggested other ways to improve the Commission's innovation allowance when we submitted an application in May

Q.13 What options would encourage competitive procurement processes for flexibility services?
We suggest the Authority support trials in the near term to support capability, test systems and processes, and to share learnings. Building agreement and clarity on the prioritisation of the value stack would be an early win for the sector. For instance, when does system security (transmission or distribution) override market (price control)? This could inform the service level agreements (SLAs) in contractual agreements between say distributors and third-party providers. SLAs are an important aspect for distributor acceptance because of our role as an essential service and our resilience obligations- services need to be there if contracted. It will also assist third parties to determine if they have a viable offering.

Operating agreements

Q.14 Have you experienced difficulties with negotiating operating agreements for flexibility services?
We publish in the 'planning our network' section of our AMP the value of distributed energy resources management alternatives[15]. This section is included in our AMP to assist potential DERM[16] providers to determine the approximate funding available from Orion when specific projects are deferred through DERM. A table provides a high-level assessment of the annual per kW cost of proposed network solutions where DERM could be used to defer the project. So far, no third parties have approached us directly to offer such services. However, through our Energy Accelerator initiative we have developed relationships that may result in exploration of new services beneficial to flexibility.
Q.15 Are the transaction costs of developing contracts a barrier to entering the market for flexibility services?
Initial costs may be high for both sides as we develop appropriate terms for early movers, but we anticipate this may reduce as these types of arrangements become more mainstream. Costs will be a partial barrier on both sides- as a distributor we have no guarantee that a negotiation will be successful and there is risk with the potential service solution. The longer a negotiation takes the greater the risk becomes in terms of delivering a viable solution. Negotiation costs may be a deterrent and additional cost to alternative solutions. In our network we have a high voltage architecture that is substantially meshed with alternative supply routes (N-1). This means that for large parts of the network non-network alternatives may not be required for some time but in saying that there will still be niche situations where they could be of benefit. We may be more likely to want them in the nearer term at the low voltage level. Solutions at this voltage level may be less costly and complex and so proportionately the negotiation costs could be lower than for higher voltages. Our experience of the DDA is that it has locked in very fixed mandatory default arrangements with little flexibility. We submit that a DDA-like approach is not a fit for purpose approach as each situation to which an alternative to a traditional network solution might be offered will be unique. Consequently, negotiation of risk-sharing and contract term would need to be situation and solution specific. Importantly, terms may need to include fixed terms, roll over provisions or review and contract break clauses. The DDA provides no provision to adjust or exit the arrangement, it is in perpetuity. This is not appropriate for the types of commercial arrangements contemplated by flexibility services. Flexibility to adopt better solutions that would be in the best interests of customers over time should not be closed off.

[15] https://www.oriongroup.co.nz/assets/Company/Corporate-publications/Orion-AMP-2021.pdf page 150
[16] Distributed energy resource management

Options, pros and cons
Q.16 Would an operating agreement help lower transaction costs and level negotiating positions?
Of the Authority's options assessment on page 56 of the paper we would support an assessment that this is a minor issue for the sector. While third party arrangements may provide benefits we also need to ensure we don't overlook our lifelines utility obligations and customer expectations on us to maintain security of supply and reliability. Recent outages have shown customers have little tolerance for this. Our preferred solution is to only go so far as to develop guidance for flexibility service agreements. It could be useful for the Authority to host a workshop with early movers and the relevant participants to understand what core key terms have developed subject to commercial sensitivities.
Q.17 What kind of operating agreement would address the issues described in this chapter?
See suggestion provided in answer to Q18. Part of this workshop could be to understand the likely risk appetite of the various parties and the primary risk matters that need to be considered to feed into guidance for flexibility service agreements.

Capability and capacity

Q.18 What are distributors doing to ensure their network can efficiently and effectively manage the transformation of networks?

Orion has or is;
• developed our strategy and is putting in place organisational change to deliver the transformation needed
• refreshing our pricing strategy and roadmap
• developing a data and digitisation strategy and roadmap
• augmenting and building strategic, data scientist and process analyst capability
• supporting sector capability through the Energy Academy[17] including through Group and sector collaboration, and partnerships with education institutions
• developing and implementing our own transformation roadmap for our network, including:
  o carrying out studies into LV network capability such as hosting capacity to understand and plan targeted reinforcement and other approaches to meeting customer needs
  o building LV models for better future operational control
  o installing targeted LV monitoring
• supporting innovation by third parties- Energy Accelerator[18]
• networking and building partnerships for better understanding
 	
EDBs do have the option to contract for services from other EDBs or third-party consultants with the capability and capacity to respond to and assess one-off larger DER requests.

Options, pros and cons
Q.19 How are distributors currently working together to achieve better outcomes for consumers?
Of the Authority's options assessment on page 60 of the paper we would support an assessment that this is a minor to medium issue for the sector. We would extend into medium specifically to encourage conversation around roles and coordination of DNO and DSO. As we mentioned elsewhere in our submission it's not necessary for everyone to be at the same stage at the same time in terms of DER however these types of initiatives help to ensure no one is left behind from a knowledge point of view even if the execution may be later for some. All South Island EDBs have recently formed the South Island Distribution Group, with the aim of developing a greater understanding of the future capabilities required for distribution system operation. This includes development of scenarios and options, as well as a stocktake of the current state of South Island EDB readiness for a high DER environment. This project has been created from the platform of collaboration that already exists between local distributors, with a history that includes the Upper South Island load management group, development of a common platform for high load transit applications, and the Collective Network Operations Group. The group will work closely with Transpower, the Commerce Commission, the Authority and IPAG as the investigation progresses, and it is hoped that progress can be made which can inform similar

[17] https://www.energyacademy.co.nz/news
[18] https://www.orionaccelerator.nz/

developments in the North Island over time. The investigation is in the early stages of understanding, with development of a draft roadmap due for completion in April 2022. South Island EDBs are also working closely with EECA and Transpower to canvas customers and catalogue the size of the transition task associated with process heat conversion from coal to renewable sources. Co-ordination on engagement and solutions will increase the efficiency of response. Increased collaboration is also being actively encouraged through the development of the collaborative platform LUMO364 and the industry sustainability group is exploring a standard approach to matters such as science-based emission reduction targets and embodied carbon reporting. We are of the view that maturity in these areas will help illustrate the desirability of flexibility services in the right context. Operational collaboration also exists through mutual aid agreements for emergency response, and contracting services being used across various EDBs. These arrangements also deliver benefit for consumers.
Q.20 Could more coordination between distributors improve the efficiency of distribution?
As mentioned in Q19 conversation about coordination and other matters are ongoing. Another area to explore, which could address supply chain risk and connection efficiency in the long term is standardisation of design (as much as possible recognising different geographic areas have different design constraints) across different networks. This would allow bulk purchase of components and sharing of resource in times of shortage or HILP events.